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Intermountain Power Project
Intermountain Generating Station
Cost Analysis of NO_x Control Technologies

B&V Project 9255
B&V File 32.0400
41.1007
June 14, 1983

Mr. James H. Anthony, Project Manager
Intermountain Power Project
Department of Water and Power
General Office Building, Room 931
P. O. Box 111
Los Angeles, California 90051

Attention: Mr. R. L. Nelson, Project Engineer

Gentlemen:

Enclosed are six (6) preliminary copies of our report, "Cost Analysis of NO_x Control Technologies for the Intermountain Power Project." These copies are being forwarded for your use in your internal and informal discussions. The report will be finalized and bound after we have received your comments and/or approval. If you have any questions concerning the enclosed report, please contact D. O. Swenson (913-967-7426).

Very truly yours,

BLACK & VEATCH

Donald O. Swenson for

Roger W. Dutton

cm
Enclosure

cc: Mr. Lowell Smith, KVB (w/copy)
Mr. Henry Nickel (w/copy)

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JUN 14 1983

Intermountain Power Project
Intermountain Generating Station

Cost Analysis of NO_x Control
Technologies for the
Intermountain Power Project

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Black & Veatch
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1.0 INTRODUCTION

Presently the Intermountain Power Project is licensed by the State of Utah to construct and operate four 750 megawatt (net) coal-fired electric generating units near Lynndyl, Utah. It has been decided to reduce the station to two 750 megawatt (net) units. The State of Utah Department of Health will be reviewing the project air quality permits pertinent to a reduction to two-unit operation at the Intermountain Generating Station (IGS) site.

Both the Environmental Project Agency (EPA) and State of Utah Department of Health (DOH) have imposed NO_x emissions requirements for the four original IGS units. The EPA requires that "each unit shall not cause to be discharged into the atmosphere nitrogen oxides, expressed as NO_2, at a rate exceeding 0.550 pounds per million Btu based on a 30-day rolling average." The DOH requires that "no boiler unit shall discharge to the atmosphere nitrogen oxides expressed as nitrogen dioxide (NO_2) at a rate exceeding 0.60 pounds NO_2 per million Btu heat input based on a 30-day rolling average of successive boiler operating days; compliance shall be accomplished by boiler design and appropriate operating practices."

The boiler is guaranteed by the manufacturer, Babcock & Wilcox to limit the nitrogen oxides emissions to 0.55 pound per million Btu (MBtu) heat input. This report evaluates the equipment requirements and differential costs of further NO_x emissions reductions at the IGS units. The following NO_x emissions control alternatives are examined as compared to the present design.

- Selective Catalytic Reduction
- Overfire Air Ports
- Flue Gas Recirculation
- Combustion Air Temperature Reduction
- Thermal $DeNO_x$ Process
- Maximum Boiler Plan Heat Release Rate Reduction

2.0 SUMMARY

2.1 SUMMARY OF IMPORTANT INFORMATION

(1) Table 2-1 summarizes the equivalent differential capital costs associated with the implementation of each specific NO_x emissions control alternative. Consideration is given to implementation of the NO_x emissions control alternative prior to commercial operation and, when applicable as a retrofit following one year of commercial operation.

(2) The economic criteria which serve as a basis for this analysis are given in Appendix A.

(3) A sample calculation outlining the procedures used for this analysis is contained in Appendix B.

TABLE 2-1. EQUIVALENT DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH IMPLEMENTATION OF NITROGEN OXIDES EMISSIONS CONTROL ALTERNATIVES.

	Installation Prior to Commercial Operation million 1986 $	Retrofit Application million 1986 $
Selective Catalytic Reduction	1,694	1,255
Overfire Air Ports	587	290
Flue Gas Recirculation	1,043	NA*
Combustion Air Temperature Reduction	904	NA
Thermal $DeNO_x$ Process	226	87
Maximum Boiler Plan Heat Release Rate Reduction	930	NA

*Not applicable.

3.0 COST ANALYSIS

This section evaluates the equivalent differential capital costs associated with the following alternatives for controlling nitrogen oxides (NO_x) emissions.

- Selective Catalytic Reduction
- Overfire Air Ports
- Flue Gas Recirculation
- Combustion Air Temperature Reduction
- Thermal $DeNO_x$ Process
- Maximum Boiler Plan Heat Release Rate Reduction

The equivalent differential capital costs include the capital costs of modifications, capitalized operating costs, and replacement power costs of unit modifications. Costs are formulated for all plans based on installation of the NO_x control alternative prior to commercial operation of the two IGS units. For three of the alternatives (Selective Catalytic Reduction, Overfire Air Ports, and Thermal $DeNO_x$ Process) retrofit installation is also considered, following one year of commercial operation.

3.1 SELECTIVE CATALYTIC REDUCTION

Selective Catalytic Reduction (SCR) can remove 80 per cent of the NO_x from the incoming flue gas stream by chemically reducing NO_x with ammonia (NH_3) to form nitrogen and water. The reaction, which requires the injection of ammonia, takes place over catalyst beds at temperatures between 480 F and 750 F. To obtain these flue gas temperatures without reheat, the SCR is placed between the economizer section of the boiler and the air heater.

Operating the SCR at temperatures below 480 F significantly increases the formation of ammonium bisulfate which is carried in the flue gas stream to the air heater. Ammonium bisulfate can severely corrode and plug the air heater. At temperatures above 750 F thermal damage to the catalyst can result. A bypass around the SCR is necessary to enable generating unit operation when temperature requirements for operating the SCR cannot be met.

Catalysts used in the SCR generally consist of vanadium or titanium dioxide compounds. Catalyst life is currently projected to be approximately two years, based on pilot plant testing completed on coal-fired units.

Ammonia for injection into the flue gas stream is stored onsite as a liquid. The ammonia is vaporized and diluted with combustion air from the air heater outlet. The diluted ammonia vapor is then injected uniformly into the flue gas stream. The size of the primary air fans must be increased to supply the additional dilution air flow. The size of the induced draft fans must also be increased to account for the additional pressure drop through the SCR system. Sootblowers are installed in the SCR to maintain clean catalyst surfaces. To reduce ash erosion and pluggage of the catalyst, a screen is installed upstream of the catalyst bed.

Even though the majority of SCR equipment is located to the side of the generating units, extensive boiler modifications are required for the flue gas ductwork to and from the SCR system. The SCR system draws boiler flue gas downstream of the economizer and returns the treated flue gas upstream of the air heater.

Babcock & Wilcox (B&W) began detailed design of the boiler backend area, (i.e., economizer, economizer hopper, air heaters, etc), about October 1981. The critical schedule path has no float for the Unit 1 commercial operation date of July 1, 1986. If a decision to implement an SCR system were made on June 1, 1983, the project schedule for the boiler will be delayed 18 months. It will be assumed that craft labor availability will not support the simultaneous construction of Units 1 and 2, therefore Unit 2 will be similarly delayed. If an SCR system is retrofitted following one year of operation, a unit outage of 6 months is anticipated.

Costs associated with the installation of an SCR system at the Intermountain Generation Station (IGS) are presented in Tables 3-1 through 3-4. Table 3-1 presents an estimate of the additional capital and operating costs to implement an SCR system. Table 3-2 presents the equivalent differential capital costs associated with initial installation of the SCR alternative. Similar data are shown in Tables 3-3 and 3-4 for retrofitting an SCR system following one year of operation. As can be seen in Tables 3-2 and 3-4 the predicted differential costs for this alternative are 1,694 million 1986 dollars and 1,255 million 1986 dollars for a new and retrofit application, respectively.

TABLE 3-~~2~~1. DIFFERENTIAL ~~BREAKDOWN OF~~ CAPITAL AND OPERATING COSTS ASSOCIATED WITH INSTALLATION OF A SELECTIVE CATALYTIC REDUCTION SYSTEM

	Unit 1 Capital Costs	Unit 2 Capital Costs	Units 1 & 2 Capital Costs
	Million $	Million $	Million $
CAPITAL COSTS (JULY 1993 dollars)			
SCR EQUIPMENT	53.5	53.5	107.0
ELECTRICAL EQUIPMENT	3.6	3.6	7.2
INCREMENTAL ID FANS	2.3	2.3	4.6
TOTAL DIRECT COSTS	~~67.7~~ 59.4	~~67.7~~ 59.4	~~135.4~~ 118.8
INDIRECT COSTS @ 14%	~~9.5~~ 8.3	~~9.5~~ 8.3	~~19.0~~ 16.6
TOTAL CAPITAL COSTS	~~77.2~~ 67.7	~~77.2~~ 67.7	~~154.4~~ 135.4
CAPITALIZED ANNUAL COSTS OF OPERATION (JULY 1986 dollars)			
AIR COMPR. DEMAND & ENERGY (30 kW)	0.1	0.1	0.2
ID ~~DRAFT~~ FAN ENERGY (36 GWH)	16.7	16.1	32.8
ID FAN DEMAND (5700 KW)	3.4	3.3	6.7
AMMONIA VAPORIZATION FUEL (17000 MBTU/YR)	4.7	4.5	9.2
AMMONIA (13000 TPY)	46.8	45.3	92.1
CATALYST (150 TPY)	273.0	264.0	537.0
LABOR & SUPPLIES	54.3	52.5	106.8
TOTAL	399.0	385.8	784.8

TABLE 3- 2. CALCULATION OF EQUIVALENT DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR Installation of a SELECTIVE CATALYTIC REDUCTION System

	UNIT 1 CAPITAL COSTS	UNIT 2 CAPITAL COSTS	UNITS 1 & 2 CAPITAL COSTS
Project	MILLION $	MILLION $	MILLION $
CAPITAL COSTS** (AS SPENT DOLLARS)	2715.0	628.0	3343.0
CAPITAL COSTS (DESCALATED TO JULY 1983 DOLLARS)	2507.0	535.0	3042.0
ADDITIONAL CAPITAL EXPENDITURE FOR SELECTIVE CATALYTIC REDUCTION (JULY 1983 DOLLARS)	67.7	67.7	135.4
TOTAL CAPITAL EXPENDITURE (JULY 1983 DOLLARS) With Selective Catalytic Reduction	2574.7	602.7	3177.4
ESCALATION *** (ALL REMAINING CASH EXPENDITURES)	325.6	147.8	
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION			
ON FUNDS ALREADY COMMITTED	266.1		
ON REMAINING FUNDS	914.3	274.4	
TOTAL CAPITAL COSTS			
UNIT 1 - JAN 1988$	4080.8		
UNIT 2 - JAN 1989$		1024.9	
PRESENT WORTH COSTS (JULY 1986 DOLLARS)			
TOTAL CAPITAL COSTS	3442.8	772.0	4214.9
CAPITALIZED VALUE OF Differential ANNUAL OPERATING COSTS	399.0	385.8	784.8
REPLACEMENT POWER COSTS DUE TO DELAY*	410.6	410.6	821.3
TOTAL COST FOR SELECTIVE CATALYTIC REDUCTION	4252.5	1568.5	5820.9
~~STATUS QUO~~ Present Design CAPITAL COST - BASED ON ORIGINAL ESTIMATE	3424.4	702.8	4127.2
EQUIVALENT DIFFERENTIAL CAPITAL COSTS ~~ASSOCIATED~~ WITH ~~PROVISIONS FOR~~ SELECTIVE CATALYTIC REDUCTION	828.1	865.7	1693.7

* DELAY REQUIRED FOR INSTALLATION OF ADDITIONAL EQUIPMENT FOR SELECTIVE CATALYTIC REDUCTION IS ESTIMATED TO BE 18 MONTHS.

** ALL CAPITAL COSTS PRESENTED INCLUDE INDIRECT COSTS at 14 per cent.

*** ESCALATION IS CALCULATED from July 1983 TO CENTER-OF-GRAVITY OF THE PROJECT CASH FLOW FOR EACH UNIT (Assumed to be ~~May~~ April 1985 and ~~April~~ May 1986 for Units 1 and 2 respectively)

TABLE 3- ~~2~~ 3. ~~BREAKDOWN OF~~ DIFFERENTIAL CAPITAL AND OPERATING COSTS ASSOCIATED WITH ~~INSTALLATION~~ RETROFIT OF A SELECTIVE CATALYTIC REDUCTION SYSTEM

	Unit 1 Capital Costs	Unit 2 Capital Costs	Units 1 & 2 Capital Costs
	Million $	Million $	Million $
CAPITAL COSTS (July 1983 ~~$~~ dollars)			
SCR EQUIPMENT	~~53.5~~ 65.6	~~53.5~~ 65.6	~~107.0~~ 132.2
ELECTRICAL EQUIPMENT	3.6	3.6	7.2
INCREMENTAL ID FANS	2.3	2.3	4.6
TOTAL DIRECT COSTS	~~67.7~~ ~~59.4~~ 71.5	~~67.7~~ ~~59.4~~ 71.5	~~135.4~~ ~~118.8~~ 143.0
INDIRECT COSTS @ 14%	~~9.5~~ ~~8.3~~ 10.0	~~8.5~~ ~~8.3~~ 10.0	~~19.0~~ 16.6
TOTAL CAPITAL COSTS	~~72.2~~ ~~67.7~~ 81.5	~~72.2~~ ~~67.7~~ 81.5	~~154.4~~ ~~135.4~~ 163.0
CAPITALIZED ANNUAL COSTS OF OPERATION (July 1986 dollars)			
AIR COMPR. DEMAND & ENERGY (30 kW)	0.1	0.1	0.2
ID ~~DRAFT~~ FAN ENERGY (36 GWH)	16.7	16.1	32.8
ID FAN DEMAND (5700 KW)	3.4	3.3	6.7
AMMONIA VAPORIZATION FUEL (17000 MBTU/YR)	4.7	4.5	9.2
AMMONIA (13000 TPY)	46.8	45.3	92.1
CATALYST (150 TPY)	273.0	264.0	537.0
LABOR & SUPPLIES	54.3	52.5	106.8
TOTAL	399.0	385.8	784.8

TABLE 3- 4. CALCULATION OF EQUIVALENT DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR INSTALLATION OF A SELECTIVE CATALYTIC REDUCTION SYSTEM AS A RETROFIT APPLICATION*

	UNIT 1 CAPITAL COSTS	UNIT 2 CAPITAL COSTS	UNITS 1 & 2 CAPITAL COSTS
	MILLION $	MILLION $	MILLION $
ADDITIONAL CAPITAL EXPENDITURE FOR RETROFIT SELECTIVE CATALYTIC REDUCTION** (JULY 1983 DOLLARS)	~~71.5~~ 81.5	~~71.5~~ 81.5	~~143.0~~ 163.0
~~INDIRECTS (14%)~~	~~10.0~~	~~10.0~~	
ESCALATION ***	30.6	39.9	
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	6.5	7.1	
TOTAL CAPITAL COSTS * ~~PRESENTED IN END OF CONSTRUCTION DOLLARS*~~ (UNIT 1 - JAN 1988) (UNIT 2 - JAN 1989)	118.~~7~~6	128.5	
PRESENT WORTH COSTS (JULY 1986 DOLLARS)			
CAPITAL COSTS FOR SELECTIVE CATALYTIC REDUCTION	100.1	96.8	196.9
CAPITALIZED VALUE OF DIFFERENTIAL ANNUAL OPERATING COSTS	399.0	385.8	784.8
REPLACEMENT POWER COSTS DUE TO INSTALLATION OUTAGE	136.9	136.9	273.8
EQUIVALENT DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR SELECTIVE CATALYTIC REDUCTION	636.0	619.5	1255.5

* CALCULATION IS BASED ~~UPON A UNIT CONSTRUCTION PERIOD OF 18 MONTHS AND A UNIT OUTAGE TIME OF 6 MONTHS.~~

*** ESCALATION IS CALCULATED TO THE CENTER-OF-GRAVITY OF THE PROJECT CASH FLOWS FOR EACH UNIT (ASSUMED TO BE JULY 1987 AND JULY 1988 FOR UNITS 1 AND 2 RESPECTIVELY).

** All capital costs presented include indirect costs at A percent.

* CALCULATION IS BASED ON A UNIT OUTAGE OF 6 MONTHS ~~FOLLOWING~~ FOLLOWING ONE YEAR OF OPERATION

Capitalized annual costs of operation shown in Tables 3-1 and 3-3 are calculated based on the consumable usage rate below each item, and the economic criteria contained in Appendix A. Operating costs reflect differential costs for 20 years of operation incurred as a function of the process requirements. Projection of differential operating costs beyond 20 years are not used in this study. The project delay costs of Table 3-2 include escalation, interest during construction, and costs for replacement power. It is assumed that the center-of-gravity of the project cash flow shifts by one-half of the delay for the respective unit when the SCR equipment is installed prior to commercial operation. Further details of cost calculation methodology are presented in the sample calculations of Appendix B. Cost data for the remaining NO_x emissions control alternatives are presented in a similar manner.

The 1986 replacement power cost is the difference between the higher cost of fuels which must be fired at other facilities when the IGS units are either delayed or not operating, and the cost of coal delivered to the IGS. Based on project economic criteria, this 1986 differential fuel cost is 48.22 mills/kWh. Multiplying the differential fuel cost by the average first-year load while operating of 706,000 kW per unit, results in a differential fuel cost of $817,000 (1986 dollars) per day. This cost is sensitive to the higher cost of fuel used at other facilities and to the IGS delivered coal cost. Current indications are that the coal cost used as the basis for economic analysis may be high. If this is the case, and if projected costs of fuel at other facilities remain unchanged, the differential fuel cost in 1986 could exceed $817,000 per day. Other charges for replacement energy, such as operating and maintenance costs, are not included. This study has assumed a relatively conservative replacement power cost of $750,000 (1986 dollars) per day, which is a lower limit value.

3.2 OVERFIRE AIR PORTS

The installation of overfire air (OFA) ports effectively reduces the concentration of oxygen in the highest temperature regions of the furnace, thus impeding NO_x formation. Some provisions for future installation of OFA ports are factored into the current boiler design. Hence, balance-of-plant costs, i.e., costs for structural steel, platforms, and heating and ventilating ductwork and piping rerouting, are minor ($500,000 for Unit 1 and $200,000 for Unit 2). However, boiler system modifications impact many areas, including the following.

- 12 OFA port inserts
- 48 revised burner openings and registers
- Windbox
- Ductwork
- Extended lance wall blowers
- Truss/buckstays
- Wall attachments
- Feeder ducts--foils/dampers
- Platforms
- Refractories, insulation, and lagging
- Boiler ties
- Controls

To maintain required burner velocities for optimum flame shape/ stabilization, the 48 burner throats and burner registers will be reduced in size.

There are nine wall blowers located on both the front and rear walls which will require extended lances. Access to these blowers is currently from the top of the windbox. Access platforms will be required across the width of the unit for maintenance.

Feeder ducts to the NO_x port plenum will be required. Feeder ducts will include all associated dampers, damper drives, and air foils. Air foils will also be added to the existing windbox inlets. Trusses will be required at the top of the NO_x port plenum on both walls possibly affecting current boiler tie locations.

Carbon monoxide (CO) emissions are expected to increase when using overfire air. The predicted costs for additional fuel required to replace the heat lost by the increased CO emissions are listed in Table 3-5. Carbon levels in the fly ash are not expected to increase with overfire air operation.

From a schedule standpoint, it is advantageous to add 12 OFA NO_x ports in the field rather than delaying boiler panel fabrication. Nonetheless,

TABLE 3-~~7~~ 5. ~~BREAKDOWN OF~~ DIFFERENTIAL CAPITAL AND OPERATING COSTS ASSOCIATED WITH THE INSTALLATION OF OVERFIRE AIR PORTS

	Unit 1 Capital Costs	Unit 2 Capital Costs	Units 1 & 2 Capital Costs
CAPITAL COSTS (July 198~~3$~~ dollars)	Million $	Million $	Million $
BOILER SYSTEMS	6.4	3.2	9.6
BALANCE OF PLANT	0.5	0.2	0.7
TOTAL DIRECT COSTS	~~7.9~~ ~~6.8~~ 6.9	~~3.9~~ 3.4	~~11.8~~ 10.3
INDIRECT COSTS @ 14%	~~1.1~~ 1.0	~~0.5~~ 0.5	~~1.7~~ 1.5
TOTAL CAPITAL COSTS	~~9.0~~ 7.9	~~4.4~~ 3.9	~~13.5~~ 11.8
CAPITALIZED ANNUAL COSTS OF OPERATION (JULY 1986 dollars)			
UNBURNED COMBUSTIBLES (1440 ~~TONS/YR~~ TPY OF FUEL)	1.1	1.1	2.2
TOTAL	1.1	1.1	2.2

if the OFA equipment is installed prior to commercial operation, the delay in the Unit 1 construction schedule is anticipated to be 14 months, extending the commercial operation date from July 1986 to September 1987. Unit 2, which is scheduled to begin commercial operation in July 1987, will be similarly delayed due to possible limitations of on-site construction personnel. If overfire air ports are installed as a retrofit after one year of commercial operation, the outage time for installation of the system is expected to be 6 months.

Costs for the installation of overfire air equipment are presented in Tables 3-5 through 3-8. As can be seen in Tables 3-6 and 3-8, the predicted costs for this alternative are 587 million 1986 dollars and 290 million 1986 dollars for a new and retrofit application, respectively.

3.3 FLUE GAS RECIRCULATION

In this alternative, approximately 15 per cent of the boiler flue gas flow is extracted at the economizer hopper and recirculated back to the hot secondary air system at the air foils, after passing through a mechanical dust collector and flue gas recirculation (FGR) fans. Costs for this alternative are summarized in Tables 3-9 and 3-10. The following are anticipated boiler system modifications needed to implement a flue gas recirculation system.

- Installation of two flue gas recirculation fans, motors, turning gears and dust collectors
- Economizer hopper redesign
- Ductwork modifications
- Convection pass redesign
- Additional refractory, insulation, and lagging
- Boiler ties relocations
- Additional boiler controls

Because of the lack of design provisions for this alternative, balance-of-plant modifications are extensive. The new ductwork will interfere with the major load-bearing structures in the boiler building, requiring a redesign of the structural steel. Heating and ventilating ductwork and piping will be rerouted, some equipment will be repositioned, and additional mechanical and electrical equipment will be required. Balance-of-plant impacts will be reduced for Unit 2 alterations.

TABLE 3- 6. CALCULATION OF EQUIVALENT DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR Installation of OVERFIRE AIR PORTS*

	UNIT 1 CAPITAL COSTS MILLION $	UNIT 2 CAPITAL COSTS MILLION $	UNITS 1 & 2 CAPITAL COSTS MILLION $
PROJECT CAPITAL COSTS** (AS SPENT DOLLARS)	2715.0	628.0	3343.0
PROJECT CAPITAL COSTS (DESCALATED TO JULY 1983 DOLLARS)	2507.0	535.0	3042.0
ADDITIONAL CAPITAL EXPENDITURE FOR OVERFIRE AIR PORTS (JULY 1983 DOLLARS)	7.9	3.9	11.8
TOTAL CAPITAL EXPENDITURE (JULY 1983 DOLLARS) WITH OVERFIRE AIR PORTS	2514.9	538.9	3053.8
ESCALATION *** (ALL REMAINING CASH EXPENDITURES)	284.6	123.3	
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION			
ON FUNDS ALREADY COMMITTED	241.4		
ON REMAINING FUNDS	816.1	225.2	
TOTAL CAPITAL COSTS			
UNIT 1 - ~~JAN~~ ~~FEB~~ SEP 1987$	3857.0		
UNIT 2 - ~~JAN~~ ~~FEB~~ SEP 1988$		887.4	
PRESENT WORTH COSTS (JULY 1986 DOLLARS)			
TOTAL CAPITAL COSTS	3379.3	694.2	4073.5
CAPITALIZED VALUE OF DIFFERENTIAL ANNUAL OPERATING COSTS	1.1	1.1	2.2
REPLACEMENT POWER COSTS DUE TO DELAY*	319.4	319.4	638.8
TOTAL COST FOR OVERFIRE AIR PORTS	3699.8	1014.7	4714.5
~~STATUS QUO~~ PRESENT DESIGN CAPITAL COST - BASED ON ORIGINAL ESTIMATE	3424.4	702.8	4127.2
EQUIVALENT DIFFERENTIAL CAPITAL COSTS ~~ASSOCIATED~~ WITH ~~PROVISIONS FOR~~ OVERFIRE AIR PORTS	275.~~5~~4	311.9	587.3

* DELAY REQUIRED FOR INSTALLATION OF ADDITIONAL EQUIPMENT FOR OVERFIRE AIR PORTS IS ESTIMATED TO BE 14 MONTHS.

** ALL CAPITAL COSTS PRESENTED INCLUDE INDIRECT COSTS at 14 per cent.

*** ESCALATION IS CALCULATED TO CENTER-OF-GRAVITY OF THE PROJECT CASH FLOW FOR EACH UNIT. From July 1983

(Assumed to be February 1985 and February 1986 for Units 1 and 2 respectively)

TABLE 3- 7. ~~BREAKDOWN OF~~ Differential CAPITAL AND OPERATING COSTS Associated With the RETROFIT OF OVERFIRE AIR PORTS

	Unit 1 Capital Costs	Unit 2 Capital Costs	Units 1 & 2 Capital Costs
	Million $	Million $	Million $
CAPITAL COSTS (June 1983 dollars)			
BOILER SYSTEMS	6.4	3.2	9.6
BALANCE OF PLANT	0.5	0.2	0.7
TOTAL DIRECT COSTS	~~7.9~~ 6.9	~~3.9~~ 3.4	~~11.8~~ 10.3
INDIRECT COSTS @ 14%	~~1.1~~ 1.0	~~0.5~~ 0.5	~~1.7~~ 1.5
TOTAL CAPITAL COSTS	~~9.0~~ 7.9	~~4.4~~ 3.9	~~13.5~~ 11.8
CAPITALIZED ANNUAL COSTS OF OPERATION (July 1986 dollars)			
UNBURNED COMBUSTIBLES (1440 ~~TONS/YR~~ TPY OF FUEL)	1.1	1.1	2.2
TOTAL	1.1	1.1	2.2

TABLE 3- 8. CALCULATION OF EQUIVALENT DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR Installation of OVERFIRE AIR PORTS AS A RETROFIT APPLICATION*

	UNIT 1 CAPITAL COSTS MILLION $	UNIT 2 CAPITAL COSTS MILLION $	UNITS 1 & 2 CAPITAL COSTS MILLION $
~~ADDITIONAL~~ CAPITAL EXPENDITURE FOR RETROFIT OVERFIRE AIR PORTS** (JULY 1983 DOLLARS)	~~6.9~~ 7.9	~~3.4~~ 3.9	~~10.3~~ 11.8
~~INDIRECTS (14%)~~	~~1.0~~	~~0.5~~	
ESCALATION ***	3.0	1.9	
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	0.6	0.3	
TOTAL CAPITAL COSTS Unit 1 – Jan 1988 Unit 2 – Jan 1989 ~~PRESENTED IN END-OF CONSTRUCTION DOLLARS*~~	11.5	6.1	
PRESENT WORTH COSTS (JULY 1986 DOLLARS)			
CAPITAL COSTS FOR OVERFIRE AIR PORTS	9.7	4.6	14.3
CAPITALIZED VALUE OF DIFFERENTIAL ANNUAL OPERATING COSTS	1.1	1.1	2.2
REPLACEMENT POWER COSTS DUE TO INSTALLATION OUTAGE	136.9	136.9	273.8
EQUIVALENT DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR OVERFIRE AIR PORTS	147.~~8~~7	142.6	290.~~2~~3

* CALCULATION IS BASED UPON ~~A UNIT CONSTRUCTION PERIOD OF 12 MONTHS AND~~ A UNIT OUTAGE TIME OF 6 MONTHS.

*** ESCALATION IS CALCULATED TO THE CENTER-OF-GRAVITY OF THE PROJECT CASH FLOWS FOR EACH UNIT (ASSUMED TO BE JULY 1987 and JULY 1988 FOR UNITS 1 and 2 RESPECTIVELY)

** All capital costs presented include indirect costs at 14 per cent.

* CALCULATION IS BASED ON A UNIT OUTAGE OF 6 MONTHS FOLLOWING ONE YEAR OF OPERATION.

Predicted capitalized costs of operation are shown in Table 3-9. Energy and demand costs are associated with the new power requirements of the FGR fans and increased power requirements of the induced draft (ID) fans. Increased ID fan power is required to overcome the increased head loss in the convective passes due to the 15 per cent flue gas flow increase.

Flue gas recirculation fans have been notably unreliable. Many existing units have removed their recirculating fan systems. Ten-year average NERC data indicate approximately 7 hours of downtime per unit-year attributable to recirculating fans. This downtime appears low, possibly due to normalization with data from units without recirculating fans, and because operation of existing FGR units is typically intermittent for steam temperature control. Replacement power costs for recirculating fan downtime are listed in Table 3-9 based on 7 hours of unit outage time per recirculating fan per year.

Increased flue gas flow will accelerate the erosion of convection pass tubes. Replacement power costs in Table 3-9 are based on a full forced outage rate of 10 hours per year or about 5 per cent of the 10-year average NERC downtime associated with superheater, reheater, and economizer tube failures.

The Unit 1 delay for FGR installation is estimated to be 2 years, delaying the Unit 1 commercial operation date from July 1986 to July 1988. Unit 2, scheduled for a July 1987 start-up, is also assumed to be delayed two years to July 1989. Equivalent differential capital costs in Table 3-10 due to the project delay and additional capital expenditures are calculated in the manner described previously. The total additional capitalized cost for installation of a flue gas recirculation system are predicted to be 1,042 million 1986 dollars.

3.4 COMBUSTION AIR TEMPERATURE REDUCTION

This alternative requires the reduction of combustion air temperatures at the Intermountain Generating Station by removing air heater surface area. According to Babcock & Wilcox, the minimum recommended combustion air temperature for coal firing is 500 F at full load, noting that poor flame stability, increased stack opacity, and increased use of oil during start-up could result. Currently, at maximum continuous rating, hot secondary air temperatures are 645 F and hot primary air temperatures are 420 F.

Differential

TABLE 3-~~12~~9. ~~BREAKDOWN OF~~ DIFFERENTIAL CAPITAL AND OPERATING COSTS ASSOCIATED WITH THE INSTALLATION OF FLUE GAS RECIRCULATION

	Unit 1 Capital Costs	Unit 2 Capital Costs	Units 1 & 2 Capital Costs
CAPITAL COSTS (July ~~1983$~~ 1983 dollars)	Million $	Million $	Million $
BOILER SYSTEMS	8.3	8.3	16.6
BALANCE OF PLANT	4.8	2.4	7.2
TOTAL DIRECT COSTS	~~14.9~~ 13.1	~~12.2~~ 10.7	~~27.1~~ 23.8
INDIRECT COSTS @ 14%	~~2.1~~ 1.8	~~1.7~~ 1.5	~~3.8~~ 3.3
TOTAL CAPITAL COSTS	~~17.0~~ 14.9	~~13.9~~ 12.2	~~30.9~~ 27.1
CAPITALIZED ANNUAL COSTS OF OPERATION (July 1986 dollars)			
FGR FAN ENERGY (~~2260 HP~~) 136WH	~~6.3~~ 6.2	6.0 ~~6.2~~	~~12.4~~ 12.2
FGR FAN ~~ENERGY~~ Demand (~~2060 HP~~) 2100KW	1.3	1.3	2.6
ID FAN ENERGY (~~725 HP~~) 3.46WH	1.6	1.~~6~~5	~~3.2~~ 3.1
ID FAN DEMAND (~~725~~ HP) 540KW	0.3	0.3	0.6
TOTAL	9.~~5~~4	~~9.3~~ 9.1	~~18.8~~ ~~18.5~~ 18.5
CAPITALIZED REPLACEMENT POWER COSTS OF OPERATION (July 1986 dollars)			
FGR FAN FAILURE (7 HR/YR/FAN)	2.2	2.2	4.4
CONVECTIVE PASS DESIGN (10 HR/YR)	3.5	3.5	7.0
TOTAL	5.7	5.7	11.4

TABLE 3-10. CALCULATION OF EQUIVALENT DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR INSTALLATION OF FLUE GAS RECIRCULATION*

	UNIT 1 CAPITAL COSTS MILLION $	UNIT 2 CAPITAL COSTS MILLION $	UNITS 1 & 2 CAPITAL COSTS MILLION $
PROJECT CAPITAL COSTS** (AS SPENT DOLLARS)	2715.0	628.0	3343.0
PROJECT CAPITAL COSTS (DESCALATED TO JULY 1983 DOLLARS)	2507.0	535.0	3042.0
ADDITIONAL CAPITAL EXPENDITURE FOR FLUE GAS RECIRCULATION (JULY 1983 DOLLARS)	14.9	12.2	27.1
TOTAL CAPITAL EXPENDITURE (JULY 1983 DOLLARS) WITH FLUE GAS RECIRCULATION	2521.9	547.2	3069.1
ESCALATION *** (ALL REMAINING CASH EXPENDITURES)	366.9	147.9	
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION			
ON FUNDS ALREADY COMMITTED	304.9		
ON REMAINING FUNDS	1007.8	281.5	
TOTAL CAPITAL COSTS			
UNIT 1 - ~~JAN~~ JULY 1988$	4201.5		
UNIT 2 - ~~JAN~~ JULY 1989$		976.~~5~~6	
PRESENT WORTH COSTS (JULY 1986 DOLLARS)			
TOTAL CAPITAL COSTS	3349.4	695.1	4044.~~4~~ 5
CAPITALIZED VALUE OF DIFFERENTIAL ANNUAL OPERATING COSTS	~~9.5~~ 9.4	9.1 ~~[illegible]~~	~~[illegible]~~ 10.5
CAPITALIZED VALUE OF ANNUAL REPLACEMENT COSTS	5.7	5.7	11.4
REPLACEMENT POWER COSTS DUE TO DELAY*	547.5	547.5	1095.0
TOTAL COST FOR FLUE GAS RECIRCULATION	3912.~~1~~0	1257.~~[illegible]~~ 4	5169.4 ~~[illegible]~~
~~STATUS QUO~~ PRESENT DESIGN CAPITAL COST - BASED ON ORIGINAL ESTIMATE	3424.4	702.8	4127.2
EQUIVALENT DIFFERENTIAL CAPITAL COSTS A~~SSOCIATED~~ WITH ~~PROVISIONS FOR~~ FLUE GAS RECIRCULATION	407.6 ~~407.2~~	554.6 ~~[illegible]~~	1042.2 ~~[illegible]~~

* DELAY REQUIRED FOR INSTALLATION OF ADDITIONAL EQUIPMENT FOR FLUE GAS RECIRCULATION IS ESTIMATED TO BE 24 MONTHS.

** ALL CAPITAL COSTS PRESENTED INCLUDE INDIRECT COSTS at 14 per cent,

*** ESCALATION IS CALCULATED FROM JULY 1983 TO CENTER-OF-GRAVITY OF THE PROJECT CASH FLOW FOR EACH UNIT (ASSUMED TO BE JULY 1985 and JULY 1986 FOR UNITS 1 and 2 RESPECTIVELY)

Reducing the heat transfer in the air heater to attain a combined 500 F combustion air temperature will result in a boiler efficiency penalty of approximately 3 per cent* and increased air heater outlet flue gas temperatures (from 280 F to approximately 390 F). The decreased boiler efficiency requires an increased fuel burn rate at all loads. Hence, fuel related systems (e.g., fuel handling, crushers, mills, etc) energy and demand costs increase. Additionally, the increased flue gas flow rate (due to reduced boiler efficiency) and increased air heater outlet flue gas temperature significantly affect the air quality control system (AQCS) and induced draft fan design and performance. The following AQCS requirement will require modifications to accommodate increased flue gas flows and temperatures.

- Flue gas desulfurization equipment
- Fabric filter equipment
- ID fans and ductwork
- AQCS building
- Additive preparation equipment
- Reheat coils
- Waste handling equipment
- AQCS control systems

The incremental capital costs listed in Table 3-11 are not for modifications to contracted equipment, but are the difference in cost between new larger equipment and the equipment currently purchased. Therefore, capital costs in Table 3-11 should be considered low.

Capitalized operating costs in Table 3-11, other than increased fuel costs, are on the same basis as the above capital costs, i.e., only those costs associated with upgrading the AQCS and ID fans are included. There are other costs (e.g., costs for increased unburned combustibles, energy and demand costs for coal handling equipment, etc) which have not been calculated. Hence, operating costs in Table 3-11 should be considered low.

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*It is assumed that the steam side of the boiler system cannot be redesigned to maintain efficiency.

TABLE 3-~~13.~~ 11 Differential ~~BREAKDOWN OF~~ CAPITAL AND OPERATING COSTS Associated with Provisions for COMBUSTION AIR TEMPERATURE REDUCTION ~~ON THE~~

	Unit 1 Capital Costs Million $	Unit 2 Capital Costs Million $	Units 1 & 2 Capital Costs Million $
CAPITAL COSTS (~~1983$~~ July dollars)			
INCREMENTAL FGD EQUIPMENT	15.0	15.0	30.0
TOTAL DIRECT COSTS	~~17.1~~ 15.0	~~17.1~~ 15.0	~~34.2~~ 30.0
INDIRECT COSTS @ 14%	~~2.4~~ 2.1	~~2.4~~ 2.1	~~4.8~~ 4.2
TOTAL CAPITAL COSTS	~~19.5~~ 17.1	~~19.5~~ 17.1	~~39.0~~ 34.2
CAPITALIZED ANNUAL COSTS OF OPERATION (July 1986 dollars)			
ADDITIONAL FUEL COSTS (3% BOILER EFFICIENCY LOSS)	51.0	50.0	101.0
AQCS ENERGY (~~6.8 GWH~~) (17 GWH)	~~2.5~~ 7.9	~~2.4~~ 7.6	4.9
AQCS DEMAND (~~1000 KW~~) (2700 KW)	~~6.9~~ 1.6	~~6.7~~ 1.5	13.6
OTHER AQCS O & M	3.8	3.7	7.5
TOTAL	~~66.2~~ 64.3	~~62.8~~ 62.0	127.0

The estimated Unit 1 delay for initial implementation of the reduced combustion air temperature alternative is 18 months, delaying commercial operation from July 1986 to January 1988. Unit 2, scheduled for commercial operation in July 1987, is assumed to be equally delayed. Equivalent differential capital costs associated with the 18-month delay and additional capital expenditures of Unit 1 and Unit 2 are listed in Table 3-12. The equivalent differential capital cost to reduce combustion air temperatures to 500 F is estimated to be $904 million 1986 dollars.

3.5 THERMAL $DeNO_x$

Exxon Research and Engineering Company has recently patented a process for NO_x removal from flue gas by the injection of ammonia into the boiler. Installation of the system, in terms of space limitations, is feasible as the majority of equipment will be located away from the boiler. Distribution of the ammonia stream will be carried out by a series of pipes running along boiler sidewalls. The thermal $DeNO_x$ system consists of the following equipment.

- Ammonia storage tanks
- Ammonia vaporizers
- Air compressors
- Automatic control system
- Ammonia injectors
- Piping, insulation, and foundations

Construction of the Thermal $DeNO_x$ system should not delay the commercial operation of Units 1 and 2 by more than 4 months. If the $DeNO_x$ system were retrofitted following one year of operation, the outage period should not exceed 2 weeks. what [illegible] HNE-4

Costs for the installation of thermal $DeNO_x$ equipment are listed in Table 3-13 through 3-16. As can be seen in Tables 3-14 and 3-16 the predicted differential costs for this alternative are 226 million 1986 dollars and 87 million 1986 dollars for a new and retrofit application respectively. These costs do not reflect any potential costs associated with additional unit unavailability or maintenance and could be subject to significant increases. These potential costs cannot be projected based upon current information for this relatively new process.

TABLE 3-12. CALCULATION OF EQUIVALENT DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR COMBUSTION AIR TEMPERATURE REDUCTION ~~[illegible]~~

STET

*

	UNIT 1 CAPITAL COSTS MILLION $	UNIT 2 CAPITAL COSTS MILLION $	UNITS 1 & 2 CAPITAL COSTS MILLION $
PROJECT CAPITAL COSTS** (AS SPENT DOLLARS)	2715.0	628.0	3343.0
PROJECT CAPITAL COSTS (DESCALATED TO JULY 1983 DOLLARS)	2507.0	535.0	3042.0
ADDITIONAL CAPITAL EXPENDITURE FOR COMBUSTION AIR TEMPERATURE REDUCTION (JULY 1983 DOLLARS)	17.1	17.1	34.2
TOTAL CAPITAL EXPENDITURE (JULY 1983 DOLLARS) WITH COMBUSTION AIR TEMPERATURE REDUCTION	2524.1	552.1	3076.2
ESCALATION *** (ALL REMAINING CASH EXPENDITURES)	318.1	135.4	
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION			
ON FUNDS ALREADY COMMITTED	266.1		
ON REMAINING FUNDS	893.1	251.4	
TOTAL CAPITAL COSTS UNIT 1 - JAN 1988$	4001.~~2~~4		
UNIT 2 - JAN 1989$		938.~~8~~9	
PRESENT WORTH COSTS (JULY 1986 DOLLARS)			
TOTAL CAPITAL COSTS	3375.8	707.2	4083.0
CAPITALIZED VALUE OF DIFFERENTIAL ANNUAL OPERATING COSTS	~~64.2~~ 64.3	62.8	127.0
REPLACEMENT POWER COSTS DUE TO DELAY*	410.6	410.6	821.~~8~~2
TOTAL COST FOR COMBUSTION AIR TEMPERATURE REDUCTION	3850.~~8~~7	1180.6	5031.~~8~~2
~~STATUS QUO~~ PRESENT DESIGN CAPITAL COST - BASED ON ORIGINAL ESTIMATE	3424.4	702.8	4127.2
EQUIVALENT DIFFERENTIAL CAPITAL COSTS ~~ASSOCIATED~~ WITH ~~PROVISIONS FOR~~ COMBUSTION AIR TEMPERATURE REDUCTION	~~[illegible]~~ 426.3	477.8	~~[illegible]~~ 904.1

* DELAY REQUIRED FOR INSTALLATION OF ADDITIONAL EQUIPMENT FOR COMBUSTION AIR TEMPERATURE REDUCTION IS ESTIMATED TO BE 18 MONTHS.

** ALL CAPITAL COSTS PRESENTED INCLUDE INDIRECT COSTS at 14 per cent.

*** ESCALATION IS CALCULATED FROM JULY 1983 TO CENTER-OF-GRAVITY OF THE PROJECT CASH FLOW FOR EACH UNIT (ASSUMED TO BE ~~AAA~~ APRIL 1985 AND APRIL 1986 FOR UNITS 1 AND 2 RESPECTIVELY)

TABLE 3-13. ~~BREAKDOWN OF~~ Differential CAPITAL AND OPERATING COSTS Associated with Installation OF A THERMAL DENOX system ~~(20% REDUCTION)~~

	Unit 1 Capital Costs	Unit 2 Capital Costs	Units 1 & 2 Capital Costs
CAPITAL COSTS (July 1983 dollars)	Million $	Million $	Million $
THERMAL DENOX EQUIPMENT	4.5	4.5	9.0
LISCENSING	2.1	2.1	4.2
TOTAL DIRECT COSTS	~~7.5~~ 6.6	~~7.5~~ 6.6	~~15.0~~ 13.2
INDIRECT COSTS @ 14%	~~1.1~~ 0.9	~~1.1~~ 0.9	~~2.1~~ 1.8
TOTAL CAPITAL COSTS	~~8.6~~ 7.5	~~8.6~~ 7.5	~~17.1~~ 15.0
CAPITALIZED ANNUAL COSTS OF OPERATION (July 1986 dollars)			
AMMONIA (3600 TPY)	13.2	12.8	26.0
DEMAND (2100 KW)	1.3	1.3	2.6
ENERGY (13.[illegible] GWH)	6.2	6.0	12.2
STEAM (4500 MBTU/YR)	1.4	1.4	2.8
TOTAL	22.1	~~21.7~~ 21.5	43.8

TABLE 3-14. CALCULATION OF EQUIVALENT DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR INSTALLATION OF A THERMAL DENOX SYSTEM (~~20% REDUCTION~~)*

PROJECT	UNIT 1 CAPITAL COSTS MILLION $	UNIT 2 CAPITAL COSTS MILLION $	UNITS 1 & 2 CAPITAL COSTS MILLION $
CAPITAL COSTS** (AS SPENT DOLLARS)	2715.0	628.0	3343.0
CAPITAL COSTS (DESCALATED TO JULY 1983 DOLLARS)	2507.0	535.0	3042.0
ADDITIONAL CAPITAL EXPENDITURE FOR THERMAL DENOX (~~20% REDUCTION~~) (JULY 1983 DOLLARS)	7.5	7.5	15.0
TOTAL CAPITAL EXPENDITURE (JULY 1983 DOLLARS) WITH THERMAL $DENO_X$	2514.5	542.5	3057.0
ESCALATION *** (ALL REMAINING CASH EXPENDITURES)	206.1	102.3	
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION			
ON FUNDS ALREADY COMMITTED	183.6		
ON REMAINING FUNDS	645.9	179.5	
TOTAL CAPITAL COSTS			
UNIT 1 - ~~JAN~~ NOV 1986$	3550.1		
UNIT 2 - ~~JAN~~ NOV 1987$		824.3	
PRESENT WORTH COSTS (JULY 1986 DOLLARS)			
TOTAL CAPITAL COSTS	3418.5	708.7	4127.2
CAPITALIZED VALUE OF DIFFERENTIAL ANNUAL OPERATING COSTS	22.1	21.~~7~~5	43.8
REPLACEMENT POWER COSTS DUE TO DELAY*	91.3	91.3	182.5
TOTAL COST FOR THERMAL DENOX (~~20% REDUCTION~~)	3531.9	821.~~8~~ 5 4	4353.5
~~STATUS QUO~~ PRESENT DESIGN CAPITAL COST - BASED ON ORIGINAL ESTIMATE	3424.4	702.8	4127.2
EQUIVALENT DIFFERENTIAL CAPITAL COSTS ~~ASSOCIATED WITH PROVISIONS FOR~~ THERMAL DENOX (~~20% REDUCTION~~)	107.5	118.~~2~~ 7	226.3

* DELAY REQUIRED FOR INSTALLATION OF ADDITIONAL EQUIPMENT FOR THERMAL DENOX (~~20% REDUCTION~~) IS ESTIMATED TO BE 4 MONTHS.

** ALL CAPITAL COSTS PRESENTED INCLUDE INDIRECT COSTS at 14 per cent.

*** ESCALATION IS CALCULATED FROM JULY 1983 TO CENTER-OF-GRAVITY OF THE PROJECT CASH FLOW FOR EACH UNIT. (ASSUMED TO BE SEPTEMBER 1984 AND SEPTEMBER 1985 FOR UNITS 1 AND 2 RESPECTIVELY)

TABLE 3-15. ~~BREAKDOWN OF~~ DIFFERENTIAL CAPITAL AND OPERATING COSTS ASSOCIATED WITH INSTALLATION OF A THERMAL DENOX SYSTEM ~~(80% REDUCTION)~~

	Unit 1 Capital Costs	Unit 2 Capital Costs	Units 1 & 2 Capital Costs
CAPITAL COSTS (July 1983~~$~~ dollars)	Million $	Million $	Million $
THERMAL DENOX EQUIPMENT	~~4.5~~ 5.4	~~4.5~~ 5.4	~~9.0~~ 10.8
LISCENSING	2.1	2.1	4.2
TOTAL DIRECT COSTS	~~7.5~~ 7.5	~~2.5~~ 7.5	~~15.0~~ 15.0
INDIRECT COSTS @ 14%	~~1.1~~ 1.1	~~1.1~~ 1.1	~~2.1~~ 2.2
TOTAL CAPITAL COSTS	~~8.6~~ 8.6	~~8.6~~ 8.6	~~17.1~~ 17.2
CAPITALIZED ANNUAL COSTS OF OPERATION (July 1986 dollars)			
AMMONIA (3600 TPY)	13.2	12.8	26.0
DEMAND (2100 KW)	1.3	1.3	2.6
ENERGY (13[illegible] GWH)	6.2	6.0	12.2
STEAM (4500 MBTU/YR)	1.4	1.4	2.8
TOTAL	22.1	~~21.7~~ 21.5	43.8

TABLE 3-~~14~~ ~~16~~ 16. CALCULATION OF EQUIVALENT DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR INSTALLATION OF A THERMAL DENOX SYSTEM ~~(20% REDUCTION)~~ AS A RETROFIT APPLICATION*

	UNIT 1 CAPITAL COSTS	UNIT 2 CAPITAL COSTS	UNITS 1 & 2 CAPITAL COSTS
	MILLION $	MILLION $	MILLION $
ADDITIONAL CAPITAL EXPENDITURE FOR RETROFIT THERMAL DENOX ~~(20% REDUCTION)~~ ** (JULY 1983 DOLLARS)	~~2.5~~ 8.6	~~2.5~~ 8.6	~~15.0~~ 17.2
~~INDIRECTS (14%)~~	~~1.1~~	~~1.1~~	
ESCALATION ***	3.2	4.2	
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	0.1	0.1	
TOTAL CAPITAL COSTS ~~PRESENTED IN END OF~~ ~~CONSTRUCTION DOLLARS~~* Unit 1 - July 1986 Unit 2 - July 1987	11.89	12.89	
PRESENT WORTH COSTS (JULY 1986 DOLLARS)			
CAPITAL COSTS FOR THERMAL DENOX ~~(20% REDUCTION)~~ DIFFERENTIAL	10.5	10.2	20.7
CAPITALIZED VALUE OF ANNUAL OPERATING COSTS	22.1	21.5	43.6
REPLACEMENT POWER COSTS DUE TO INSTALLATION OUTAGE	11.4	11.4	22.8
EQUIVALENT DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR THERMAL DENOX ~~(20% REDUCTION)~~	44.0	43.1	87.1

* CALCULATION IS BASED UPON A UNIT CONSTRUCTION PERIOD OF ~~1 MONTHS AND A UNIT OUTAGE TIME OF .5 MONTHS.~~

*** ESCALATION IS CALCULATED TO THE CENTER-OF-GRAVITY OF THE PROJECT CASH FLOWS for Each Unit (Assumed to be July 1987 and July 1988 for Units 1 and 2 Respectively).

** All capital costs presented include indirect costs at 14 percent.

*Calculation is based on a unit outage time of two weeks following one year of operation.

3.6 MAXIMUM BOILER PLAN HEAT RELEASE RATE REDUCTION

Nitrogen oxides emissions are reduced with this alternative, by lowering the maximum plan heat release rate ($MBtu/hr-ft^2$) at which the boiler can operate. To maintain proper steam flow, the boiler plan (cross-sectional) area can be altered only by total redesign of the boiler and surrounding structures which will result in excessive project delay and expense. However, the heat release rate can be lowered by decreasing the boiler heat input and, thus, maximum load capability.

According to Babcock & Wilcox, for unit operation at 75 per cent load, the NO_x output is predicted to be 0.38 lb/MBtu (pound NO_x per million Btu) as compared to 0.55 lb/MBtu for operation at the maximum continuous rating. A curve depicting the Babcock & Wilcox expected NO_x emissions as a function of load is presented on Figure 3-1. Expected NO_x emissions as a function of heat input per plan area are tabulated below.

Load per cent	Heat Input per Plant Area $MBtu/hr-ft^2$	Expected NO_x Emissions lb/MBtu
MCR	1.60	0.55
100	1.48	0.53
75	1.10	0.38

Costs associated with this alternative are calculated by determining the total number of megawatt-hours which must be replaced by other sources based upon the projected load curve. For example, the capitalized operating cost for limiting the heat input per plan area to 1.1 $MBtu/hr-ft^2$ (75 per cent load) is $465 million 1986 dollars per unit for a reduction in NO_x emissions of 0.17 lb/MBtu. As listed in Table 3-17 the predicted differential captial cost for this alternative is 930 million 1986 dollars for the two unit station.

TABLE 3-~~15~~ ~~16~~ 17. CALCULATION OF EQUIVALENT DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR REDUCING THE MAXIMUM HEAT INPUT~~*~~ TO THE BOILER

	UNIT 1 CAPITAL COSTS MILLION $	UNIT 2 CAPITAL COSTS MILLION $	UNITS 1 & 2 CAPITAL COSTS MILLION $
PROJECT CAPITAL COSTS~~**~~ (AS SPENT DOLLARS)	2715.0	628.0	3343.0
PROJECT CAPITAL COSTS (DESCALATED TO JULY 1983 DOLLARS)	2507.0	535.0	3042.0
ADDITIONAL CAPITAL EXPENDITURE FOR REDUCING MAXIMUM HEAT INPUT (JULY 1983 DOLLARS)	0.0	0.0	0.0
TOTAL CAPITAL EXPENDITURE (JULY 1983 DOLLARS)	2507.0	535.0	3042.0
ESCALATION ~~***~~ (ALL REMAINING CASH EXPENDITURES)	174.9	92.5	
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION			
ON FUNDS ALREADY COMMITTED	162.0		
ON REMAINING FUNDS	580.5	159.6	
TOTAL CAPITAL COSTS			
UNIT 1 - ~~JAN~~ JULY 1986$	3424.4		
UNIT 2 - ~~JAN~~ JULY 1987$		787.1	
PRESENT WORTH COSTS (JULY 1986 DOLLARS)			
TOTAL CAPITAL COSTS	3424.4	702.8	4127.2
CAPITALIZED VALUE OF ANNUAL REPLACEMENT COSTS	465.0	465.0	930.0
TOTAL COST FOR REDUCING MAXIMUM HEAT INPUT	3889.4	1167.8	5057.2
~~STATUS QUO~~ PRESENT DESIGN CAPITAL COST - BASED ON ORIGINAL ESTIMATE	3424.4	702.8	4127.2
EQUIVALENT DIFFERENTIAL CAPITAL COSTS ASSOCIATED WITH PROVISIONS FOR REDUCING MAXIMUM HEAT INPUT	465.0	465.0	930.0

~~* DELAY REQUIRED FOR INSTALLATION OF ADDITIONAL EQUIPMENT FOR REDUCING MAXIMUM HEAT INPUT IS ESTIMATED TO BE 0 MONTHS.~~

~~**~~ ALL CAPITAL COSTS PRESENTED INCLUDE INDIRECT COSTS at 14 per cent,

~~***~~ ESCALATION IS CALCULATED FROM JULY 1983 TO CENTER-OF-GRAVITY OF THE PROJECT CASH FLOW FOR EACH UNIT (Assumed to be July 1984 and July 1985 for Units 1 and 2 respectively).

APPENDIX A
CRITERIA FOR ECONOMIC EVALUATION

The Intermountain Generating Station (Units 1 and 2) is being developed by the Intermountain Power Agency. The cities of Anaheim, Burbank, Glendale, Los Angeles, Pasadena, and Riverside in southern California, Utah Power and Light, and Intermountain Consumers Power Association (ICPA) have contracted to purchase the power produced by the station. This report uses the following economic criteria.

Evaluation Period

The evaluation period for each unit will be 35 years.

Unit	Evaluation Period
1	July 1, 1986 to June 30, 2021
2	July 1, 1987 to June 30, 2022

Operating costs for this study will be capitalized over 20 years.

1. Present Worth Discount Rate and Present Worth Factors.

The present worth concept is a method of taking into account the time value of money. Using an interest rate, also called the present worth discount rate, present worth factors are developed which can be used to convert future expenditures to an equivalent single value at one point in time.

For investor-owned utilities, the present worth discount rate is considered to be their weighted average cost of capital, considering both the cost of debt capital (bonds) and the cost of equity capital (preferred stock, common stock, and retained earnings). For publicly-owned utilities, which usually have 100 per cent bond financing, the present worth discount rate is considered to be equal to the estimated bond interest rate.

The factors most commonly used in present worth arithmetic are the Single Payment Present Worth Factor, the Uniform Series Present Worth Factor, and the Capital Recovery Factor, as shown in the following tabulation and discussed in the following paragraphs.

Factor	Abbrev.	Functional Symbol	Forumual Used to Calculate Factor
Single Payment Present Worth Factor	PWF	P/F, i, n	$\frac{1}{(1+i)^n}$
Uniform Series Present Worth Factor	USPWF	P/A, i, n	$\sum_{1}^{n}$ PWF, or $\frac{1-\frac{1}{(1+i)^n}}{i}$
Capital Recovery Factor	CRF	A/P, i, n	$\frac{1}{\text{USPWF}}$, or $\frac{i}{1-\frac{1}{(1+i)^n}}$

The functional symbols are those used in the textbook Principles of Engineering Economy by Grant, Ireson, and Leavenworth. They are based on the following.

- i--Interest rate per period.
- n--Number of interest periods.
- P--Present sum of money.
- F--Future sum of money equivalent to P.
- A--End-of-year payment in a uniform series with entire series equivalent to P.

Single Payment Present Worth Factor (PWF). To determine the present worth of a future single expenditure, multiply the future expenditure by PWF. For example, the present worth of $1,000 spent three years after the beginning of the study period, with an interest rate, or present worth discount rate, of 12 per cent would be calculated as follows.

$$\text{PWF} = \frac{1}{(1+i)^n} = \frac{1}{(1.12)^3} = .7118$$

Present Worth = $1,000 X .7118 = $711.80

Uniform Series Present Worth Factor (USPWF). To determine the present worth of a uniform series of payments, multiply the payment by USPWF. For example, find the present worth of a series of 5 annual payments, each equal to $500, with the first payment occurring one year after the beginning of the study period. Assume a present worth discount rate of 12

$$\text{USPWF} = \frac{1 - \frac{1}{(1+i)^n}}{i} = \frac{1 - \frac{1}{(1.12)^5}}{.12} = 3.6048$$

Present worth = $500 X 3.6048 = $1802.40

Capital Recovery Factor (CRF). Given a present sum of money, to find the constant amount payable at the end of each year such that the present worth of the uniform series is equal to the present sum, multiply the present sum by CRF. For example, if the present sum is $2,000, find the equal annual payment to be paid for 5 years that will have an equivalent present worth to $2,000. Assume a present worth discount rate of 12 per cent.

$$\text{CRF} = \frac{i}{1 - \frac{1}{(1+i)^n}} = \frac{.12}{1 - \frac{1}{(1.12)^5}} = .27741$$

Equal annual payment = $2,000 X .27741 = $554.82

Tables listing these factors for many combinations of interest rates and numbers of interest periods can be found in most economic textbooks.

The present worth discount rate for the Intermountain Generating Station is 12.0 per cent applied to one-year periods with July 1, 1986 to June 30, 1987 being the first year. The compound interest factors for 12.0 per cent are listed on Table 41.0100-1. With July 1, 1986 as the base for present worth determinations, the sums of annual present worth factors for Unit 1 and for the station are as follows.

	Evaulation Period	Uniform Series Present Worth Factor
Unit 1	35 years	8.1755
Units 1 and 2	36 Years	8.1924

2. Escalation Rates.

Equipment costs and labor costs have increased steadily for many years and are expected to continue to increase. Escalation results from two principal influences: the decreasing value of the dollar (due to "inflation"), and the effect of reduced supply with respect to demand ("Real escalation"). Total escalation can be expressed in terms of its two components by the following equation:

$$(1 + e) = (1 + e_r)(1 + j), \text{ where}$$

e = total escalation rate, decimal

e_r = real escalation rate, decimal

j = inflation rate, decimal

The following terminology is used in discussing various aspects of escalation.

Escalation Rate--The total escalation rate, sometimes called "apparent escalation rate," that includes both inflation and real escalation.

Inflation Rate--The annual rate of increase in the general price level of all goods and services which results in a decreased value of the dollar over time. Government indices used to quantify inflation are the Gross National Product (GNP) implicit price deflator and the Producer Price Index (formerly the Wholesale Price Index).

Real Escalation Rate--The annual rate of increase in the price of a particular product or service, independent of inflation. Factors that cause real escalation include resource depletion, reduced productivity, increased demand, and increased government regulation.

TABLE 41.0100-1. 12.0 PER CENT COMPOUND INTEREST FACTORS

		Single Payment		Uniform Series			
n	Year Starting July 1	Compound Amount Factor $(1+i)^n$	Present Worth Factor $\frac{1}{(1+i)^n}$	Sinking Fund Factor $\frac{i}{(1+i)^n-1}$	Capital Recovery Factor $\frac{i(1+i)^n}{(1+i)^n-1}$	Compound Amount Factor $\frac{(1+i)^n-1}{i}$	Present Worth Factor $\frac{(1+i)^n-1}{i(1+i)^n}$
1	1986	1.1200	.8929	1.0000	1.1200	1.0000	.8929
2	1987	1.2544	.7972	.4717	.5917	2.1200	1.6901
3	1988	1.4049	.7118	.2963	.4163	3.3744	2.4018
4	1989	1.5735	.6355	.2092	.3292	4.7793	3.0373
5	1990	1.7623	.5674	.1574	.2774	6.3528	3.6048
6	1991	1.9738	.5066	.1232	.2432	8.1152	4.1114
7	1992	2.2107	.4523	.0991	.2191	10.0890	4.5638
8	1993	2.4760	.4039	.0813	.2013	12.2997	4.9676
9	1994	2.7731	.3606	.0677	.1877	14.7757	5.3282
10	1995	3.1058	.3220	.0570	.1770	17.5487	5.6502
11	1996	3.4786	.2875	.0484	.1684	20.6546	5.9377
12	1997	3.8960	.2567	.0414	.1614	24.1331	6.1944
13	1998	4.3635	.2292	.0357	.1557	28.0291	6.4235
14	1999	4.8871	.2046	.0309	.1509	32.3926	6.6282
15	2000	5.4736	.1827	.0268	.1468	37.2797	6.8109
16	2001	6.1303	.1631	.0234	.1434	42.7533	6.9740
17	2002	6.8660	.1456	.0205	.1405	48.8837	7.1196
18	2003	7.6900	.1300	.0179	.1379	55.7497	7.2497
19	2004	8.6128	.1161	.0158	.1358	63.4397	7.3658
20	2005	9.6463	.1037	.0139	.1339	72.0524	7.4694
21	2006	10.8038	.0926	.0122	.1322	81.6987	7.5620
22	2007	12.1003	.0826	.0108	.1308	92.5026	7.6446
23	2008	13.5523	.0738	.0096	.1296	104.6029	7.7184
24	2009	15.1786	.0659	.0085	.1285	118.1552	7.7843
25	2010	17.0001	.0588	.0075	.1275	133.3339	7.8431
26	2011	19.0401	.0525	.0067	.1267	150.3339	7.8957
27	2012	21.3249	.0469	.0059	.1259	169.3740	7.9426
28	2013	23.8839	.0419	.0052	.1252	190.6989	7.9844
29	2014	26.7499	.0373	.0047	.1247	214.5828	8.0218
30	2015	29.9599	.0334	.0041	.1241	241.3327	8.0552
31	2016	33.5551	.0298	.0037	.1237	271.2926	8.0850
32	2017	37.5817	.0266	.0033	.1233	304.8477	8.1116
33	2018	42.0915	.0238	.0029	.1229	342.4294	8.1354
34	2019	47.1425	.0212	.0026	.1226	384.5210	8.1566
35	2020	52.7996	.0189	.0023	.1223	431.6635	8.1755
36	2021	59.1356	.0169	.0021	.1221	484.4631	8.1924
37	2022	66.2318	.0151	.0018	.1218	543.5987	8.2075
38	2023	74.1797	.0135	.0016	.1216	609.8305	8.2210
39	2024	83.0812	.0120	.0015	.1215	684.0102	8.2330
40	2025	93.0510	.0107	.0013	.1213	767.0914	8.2438

Note: i = interest rate per interest period

n = number of interest periods

Actual Dollars--The expected cost with the effect of inflation included, sometimes called current dollars. It reflects the actual out-of-pocket cost that one would expect to pay for the goods or services being considered in a particular year.

Real Dollars--The expected cost with the effect of inflation removed, sometimes called constant dollars. These dollar amounts should be expressed in terms of a certain year, for example, in 1986 dollars.

Calculations of escalated costs are usually made by annual compounding. Sometimes, it is necessary to escalate costs on a monthly rather than an annual basis. The monthly escalation rate is computed by the following formula:

$$(1 + e_m) = (1 + e)^{1/12}, \text{ where}$$

e_m = monthly escalation rate, decimal

e = annual escalation rate, decimal

For large projects such as power plants, it is usually assumed for simplicity that the entire cost of the project is spent as a lump sum at the center-of-gravity of the project cash flow for each unit which is usually near the midpoint of the unit's construction period. Typically, for large coal-fired power plants the construction period is normally assumed to be approximately four years, so escalation for such plants is computed up to two years before the scheduled date for commercial operation which is the midpoint of the construction period.

The anticipated Intermountain Generating Station escalation rate for equipment and materials are as follows.

Item	Period	Escalation Rate Compounded Yearly per cent	Escalation Rate Compounded Monthly per cent
	1/1/83 to 12/31/89	8.3	0.6667
	1/1/90 and thereafter	7.0	0.5654

In most cases, escalated direct capital costs of equipment and materials will be the costs anticipated to be in effect two years before commercial operation which is considered to be the center-of-gravity of the project cash flow for each unit. For example, direct capital costs for Unit 1 will be determined as of July 1, 1984.

3. Indirect Costs.

Capital cost estimates for power plants include an item for indirect costs which is usually calculated as a percentage of escalated direct costs. The direct costs consist of total costs for each contract. Contract costs comprise costs for procurement of equipment and materials, installation, and general construction.

Indirect costs include expenses for engineering services, field construction management services, and Owner costs.

Indirect capital costs for the Intermountain Generating Station are 14 per cent of direct capital costs. Indirect capital costs include engineering, construction management, and Owner legal, administrative, and overhead costs.

4. Allowance for Funds Used During Construction (AFUDC).

The interest paid on money spent to construct a power plant is called Allowance for Funds Used During Construction; it is usually abbreviated AFUDC.

AFUDC is calculated for payments made during the time from the start of the project until the commercial operation date and is listed as a separate cost account in the total capital cost of the plant.

AFUDC is calculated by the following method which is used when information on payment and delivery dates is not available. Assume that all payments are made in a lump sum at the center-of-gravity of the project cash flow for each unit and calculate the interest from the center-of-gravity of the project cash flow until the date of commercial operation. This method is normally used in cost estimates for systems analyses, and it is also used for preliminary total plant cost estimates.

An allowance for funds used during construction is applied to the direct capital cost of equipment and materials after adjustments for indirect costs, and escalation. For the Intermountain Generation Station the AFUDC rate starting in 1983 and thereafter is 12.0 per cent compounded annually. Typically, the AFUDC rate is applied for the two-year period from the center-of-gravity of the project cash flow for each unit to the unit's date of commercial operation.

5. Capital Equivalent Cost Method.

This method is used to compare alternative plans on the basis of total capital equivalent cost. The differential operating costs for 20 years of operation are expressed as capital equivalent operating costs and are added to the capital cost to obtain a total capital equivalent cost.

The capital equivalent operating costs are determined by dividing the levelized operating costs by the levelized annual fixed charge rate.

6. General Economic Criteria.

Levelized Annual Fixed Charge Rate

The levelized annual fixed charge rate, based on a generating unit life of 35 years and a zero net salvage value, is 13.19 per cent.

Incremental Demand Cost

The incremental demand cost to be used in comparing alternative design concepts is $600 per kilowatt. The levelized annual demand charge is $79.14 per kilowatt-year ($600 x 0.1319).

Load Model

The single-unit load model used for economic evaluations is presented as Table 41.0100-2. Total life of each unit is 306,600 hours (35 years) during which it will operate 250,755 hours and be inactive 55,845 hours.

Energy Costs

The 20 year cumulative present worth of energy costs is 500.76 mills/kWh.

Ammonia Costs

The July 1983 cost of ammonia is 250 dollars per ton.

Catalyst Costs

Catalyst costs for the Selective Catalytic Reduction system was assumed to be 125,000 $/ton in July 1983 dollars.

TABLE 41.0100-2. GENERATING UNIT LOAD MODEL

Year(s)*						
Unit 1		1986-2000	2001-2005	2006-2010	2011-2015	2016-2020
Unit 2		1987-2001	2002-2006	2007-2011	2012-2016	2017-2021
Unit Age (years)		1-15	16-20	21-25	26-30	31-35
Output per cent	Gross Output MW	OPERATING TIME--HOURS PER YEAR PER UNIT				
100	820	5,694	5,256	4,380	3,504	2,628
75	615	1,752	1,472	1,314	1,156	1,752
50	410	0	718	1,533	2,348	1,752
Hours of Operation		7,446	7,446	7,227	7,008	6,132
Hours Inactive		1,314	1,314	1,533	1,752	2,628
Annual Capacity Factor, per cent		80.0	76.7	70.0	63.3	55.0
Capacity Factor While Operating, per cent		94.1	90.2	84.8	79.1	78.6
Unit Life (35 yr) Capacity Factor, per cent		72.1				
Unit Life (35 yr) Avg. Load While Operating, per cent		87.9				

*Time interval begins July 1 of the stated year and ends June 30 of the following year.

APPENDIX B

SAMPLE CALCULATION TO ILLUSTRATE EFFECT OF FURTHER NO_x EMISSIONS REDUCTION ON PROJECT COSTS

BLACK & VEATCH CONSULTING ENGINEERS

Owner INTERMOUNTAIN POWER PROJECT

Plant INTERMOUNTAIN GENERATING STATION Unit 1&2

Project No. 9655.D32 File No.

Title SAMPLE CALCULATION TO ILLUSTRATE THE EFFECT OF INSTALLATION OF A FLUE GAS RECIRCULATION SYSTEM ON PROJECT COSTS

Computed By JeCochran

Date JUNE 13 1983

Checked By

Date 19

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APPENDIX B

THIS EXAMPLE CALCULATION WILL ILLUSTRATE HOW THE EQUIVALENT DIFFERENTIAL CAPITAL COST IS COMPUTED FOR INSTALLATION OF A FLUE GAS RECIRCULATION SYSTEM AT THE INTERMOUNTAIN GENERATING STATION (IGS).

UNITS 1 and 2 OF THE IGS ARE CURRENTLY SCHEDULED FOR COMMERCIAL OPERATION IN JULY 1986 AND JULY 1987 RESPECTIVELY. THE CURRENT CONTRACT COSTS FOR THE IGS UNITS 1&2 ARE AS FOLLOWS.

	Contract Costs (as-spent basis) (10^6 \$)
UNIT 1	2715
UNIT 2	628
TOTAL	3343

THESE CONTRACT COSTS ARE IN "AS-SPENT DOLLARS" AND ARE ASSUMED TO BE ESCALATED TO THE CENTER-OF-GRAVITY OF THE PROJECT CASH FLOW FOR EACH UNIT. CONTRACT COSTS INCLUDE INDIRECT COSTS SUCH AS ENGINEERING SERVICES, FIELD CONSTRUCTION MANAGEMENT SERVICES, ETC. ARE INCLUDED IN CONTRACT COSTS. THE CENTER-OF-GRAVITY OF THE PROJECT CASH FLOW FOR UNITS 1 AND 2 ARE JULY 1984 AND JULY 1985 RESPECTIVELY. TO CONVERT THESE CONTRACT COSTS INTO A CONSISTENT SET OF JULY 1983 CAPITAL COSTS IT WILL BE NECESSARY TO DE-ESCALATE THESE CONTRACT COSTS BY 8.3% PER YEAR.

	CAPITAL COSTS (10^6 \$ JULY 1983)
UNIT 1	2507
UNIT 2	535
TOTAL	3042

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Owner IPP
Plant IGS Unit 1&2
Project No. 9255 D32 File No.
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THESE CAPITAL COSTS INCLUDE SALES TAX WHERE APPLICABLE. THESE COSTS CONSIST OF TOTAL COSTS FOR EACH CONTRACT, INCLUDING PROCUREMENT OF EQUIPMENT AND MATERIALS, INSTALLATION, AND GENERAL CONSTRUCTION.

THE INCREMENTAL CAPITAL COSTS (JULY 1983 DOLLARS) FOR THE INSTALLATION OF A FLUE GAS RECIRCULATION SYSTEM ARE AS FOLLOWS.

	INCREMENTAL DIRECT CAPITAL COST (10^6 \$ 1983)	INDIRECTS (@14%)	INCREMENTAL CAPITAL COST (10^6 \$ 1983)
UNIT 1	13.1	1.8	14.9
UNIT 2	10.7	1.5	12.2
TOTAL	23.8	3.3	27.1

THEREFORE THE TOTAL CAPITAL EXPENDITURE IN JULY 1983 DOLLARS FOR UNITS 1 AND 2 WITH AN FGR SYSTEM ARE AS FOLLOWS.

	BASE PLANT CAPITAL COST (10^6 \$ 1983)	ADDITIONAL EXPENDITURE FOR FGR (10^6 \$ 1983)	TOTAL CAPITAL EXPENDITURE (10^6 \$ 1983)
UNIT 1	2507	14.9	2521.9
UNIT 2	535	12.2	547.2
TOTAL	3042	27.1	3069.1

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Plant IGS Unit 1&2
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COMMERCIAL OPERATION OF UNITS 1&2 WILL BE DELAYED 24 MONTHS IF THE DECISION TO IMPLEMENT AN FGR SYSTEM WERE MADE. THESE CHANGES WILL AFFECT THE CENTER-OF-GRAVITY OF THE PROJECT CASH FLOWS BY APPROXIMATELY HALF OF THE PROJECT DELAY. THE ADJUSTED MILESTONE DATES WOULD BE AS FOLLOWS

	DELAYED CENTER-OF GRAVITY OF THE PROJECT CASH FLOWS	DELAYED UNIT START-UP
UNIT 1	JULY 1985	JULY 1988
UNIT 2	JULY 1986	JULY 1989

FOR THE PURPOSES OF THIS EVALUATION IT WILL BE ASSUMED THAT ALL PAYMENTS ARE MADE IN A LUMP SUM AT THE CENTER-OF GRAVITY OF THE PROJECT CASH FLOW. IT WILL THEN BE NECESSARY TO ESCALATE CALCULATED 1983 CAPITAL COSTS TO THE CENTER-OF-GRAVITY OF THE PROJECT CASH FLOW. CAPITAL COSTS ARE EXPECTED TO ESCALATE AT AN ANNUAL RATE OF 8.3%. AS OF JUNE 1, 1983, $400,000,000 WILL HAVE BEEN SPENT ON UNIT 1. MONEY ALREADY SPENT ON THE PROJECT WILL NOT BE ESCALATED.

	1983 CAPITAL COST (10^6 $ 1983)	REMAINING EXPENDITURES (10^6 $)	ESCALATION TO CENTER-OF-GRAVITY (10^6 $)	REMAINING EXPENDITURES CENTER-OF-GRAVITY CAPITAL COST (10^6 $)
UNIT 1	2521.9	2121.9	366.9	2488.8
UNIT 2	547.2	547.2	147.9	695.1

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THE INTEREST PAID ON MONEY SPENT TO CONSTRUCT UNITS 1&2 IS CALLED ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC). AFUDC IS CALCULATED FOR PAYMENTS MADE DURING THE PERIOD FROM THE START OF THE PROJECT UNTIL THE COMMERCIAL OPERATION DATE AND IS LISTED AS A SEPARATE COST ACCOUNT IN THE TOTAL CAPITAL COST OF THE PLANT. AFUDC FOR THE IGS UNITS WILL BE CALCULATED USING THE RATE OF 12% PER YEAR FROM THE CENTER-OF-GRAVITY TO THE DATE OF COMMERCIAL OPERATION. FOR FUNDS ALREADY COMITTED, AFUDC WILL BE CALCULATED FROM THE EXPENDITURE DATE TO THE END OF CONSTRUCTION. AFUDC FOR UNIT 1 WILL BE CALCULATED FROM CALCULATED FROM JULY 1985 TO JULY 1988 EXCLUDING THE 400×10^6 ALREADY SPENT. AFUDC ON 400×10^6 ALREADY SPENT IS CALCULATED FROM JULY 1983 TO JULY 1988. AFUDC FOR UNIT 2 IS FROM JULY 1986 TO JULY 1989.

AFUDC ON FUNDS ALREADY COMITTED = $400(1.12^5 - 1) = 304.9\ (10^6\$)$

	Remaining Expenditure Center-of-Gravity Capital Cost $(10^6\$)$	AFUDC on Remaining Expenditures $(10^6\$)$
Unit 1	2488.8	1007.8
Unit 2	695.1	281.5

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Plant IGS	Unit 1 & 2	Date 6/14 1983	
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THEREFORE THE COMPARATIVE CAPITAL COSTS FOR IGS UNITS 1 & 2 ARE AS FOLLOWS.

	UNIT 1 (10^6 \$)	UNIT 2 (10^6 \$)
BASE CAPITAL COST	2507.0	535.0
INCREMENTAL CAPITAL COST	14.9	12.2
TOTAL CAPITAL EXPENDITURE (JULY 1983)	2521.9	547.2
ESCALATION	3660.9	147.9
AFUDC - FUNDS ALREADY COMMITTED	304.9	
- ON REMAINING EXPENDITURES	1007.8	281.5
TOTAL CAPITAL COSTS		
UNIT 1 - 7/1988	4201.5	
UNIT 2 - 7/1989		976.6

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TO GET CAPITAL COSTS ONTO A CONSISTENT BASIS IT WILL BE NECESSARY TO PRESENT WORTH COSTS BACK TO JULY 1986 DOLLARS. THE PRESENT WORTH DISCOUNT RATE IS 12% PER YEAR. THE PRESENT WORTH FACTOR IS CALCULATED USING THE FOLLOWING FORMULA.

$$\text{PRESENT WORTH FACTOR} = 1/(1+\text{PWDR})^n$$

WHERE PWDR IS THE PRESENT WORTH DISCOUNT FACTOR AND n IS THE NUMBER OF YEARS

THEREFORE THE JULY 1986 UNITS 1&2 CAPITAL COSTS WOULD BE AS FOLLOWS.

	TOTAL CAPITAL COST (10^6\$)	DISCOUNT YEARS	PRESENT WORTH FACTOR	JULY 1986 PW OF TOTAL CAP COSTS (10^6\$)
UNIT 1	4201.5	2	0.797	3349.4
UNIT 2	976.6	3	0.712	695.1

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CAPITALIZED VALUE OF OPERATING COSTS

ECONOMIC CRITERIA:

35 YR FIXED CHARGE RATE = 13.19%
35 YEAR Σ PW FACTORS = 8.1755
CAPACITY FACTOR = 72.1%
ESCALATION RATE = 8.3%
PRES. WORTH DISC RATE = 12.0%
20 YEAR CUM. PW ENERGY COSTS = 500.76 mills/kwh
DEMAND CHARGE = 600 $/kW
20 YEAR CUM. PW REPL. POWER COSTS = 557.68 mills/kwh

THE TWO FLUE GAS RECIRCULATION WILL HAVE A SPECIFIC ENERGY DEMAND. IT IS ESTIMATED THAT THE DEMAND WILL BE 2100 KW. THEREFORE THE 1986 CAPITALIZED OPERATING COST FOR DEMAND IS CALCULATED AS FOLLOWS.

CAPITALIZED DEMAND COST FOR UNIT 1 FGR FANS $= (2100 \text{ kW})(600 \text{ \$/kW}) = 1.3 \times 10^6$ (1986 $)

UNIT 2 $= 1.3 \times 10^6 \left(\frac{1.083}{1.12}\right) = 1.3 \times 10^6$ (1986 $)

THE FANS WILL REQUIRE ENERGY WHICH CAPITALIZED OPERATING COST IS CALCULATED AS FOLLOWS.

CAPITALIZED ENERGY COST FOR UNIT 1 FGR FANS $= \dfrac{(2100 \text{ kW})(8760 \text{ HR/YR})(0.721)\left(\frac{0.50076 \text{ \$/kwh}}{8.1755}\right)}{0.1319} \$ = 6.2 \times 10^6$ (198

UNIT 2 $= 6.2 \times 10^6 \left(\frac{1.083}{1.12}\right) = 6.0 \times 10^6$ (1986 $)

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DUE TO THE INCREASED PRESSURE DROP THE ID FANS WILL HAVE TO BE INCREASED IN SIZE BY APPROXIMATELY 540 kW INCURRING THE FOLLOWING ENERGY AND DEMAND CHARGES.

CAPITALIZED DEMAND COST FOR UNIT 1 INCREMENTAL ID FAN $= (540)(600) = 0.3 \times 10^6$ (\$1986)

$$\text{UNIT 2} = 0.3 \times 10^6 \left(\frac{1.083}{1.12}\right) = 0.3 \times 10^6$$

CAPITALIZED ENERGY COST FOR UNIT 1 INCREMENTAL ID FAN

$$= \frac{(540\text{ kW})(8760)(0.721)\left(\frac{0.50070}{8.1755}\right)}{0.1319} = 1.6 \times 10^6 \ (\$1986)$$

$$\text{UNIT 2} = 1.6 \times 10^6 \left(\frac{1.083}{1.12}\right) = 1.5 \times 10^6 \ (\$1986)$$

SUMMING THE SPECIFIC CAPITALIZED OPERATING COSTS YIELDS THE FOLLOWING TOTALS.

	UNIT 1 (10^6 \$1986)	UNIT 2 (10^6 \$1986)
FGR FAN DEMAND	1.3	1.3
FGR FAN ENERGY	6.2	6.0
Δ ID FAN DEMAND	0.3	0.3
Δ ID FAN ENERGY	1.6	1.5
TOTAL	9.4	9.1

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CAPITALIZED REPLACEMENT POWER COSTS

THE TWO FGR FANS WILL BE FORCED OUT OF OPERATION APPROXIMATELY 7 HOURS PER YEAR PER FAN.

THE UNIT WILL OPERATE AT 100% LOAD 65% OF THE TIME AND AT 75% LOAD 20% OF THE TIME. THEREFORE THE GENERATION LOST DUE TO FAN OUTAGES WILL BE AS FOLLOWS, (ASSUMING THAT IF ONE FAN IS LOST THE UNITS CAPACITY WILL DECREASE TO HALF OF THE MAXIMUM).

$$\text{GENERATION LOST} = 14\ \text{hr/yr}\left[0.65(\underset{100\%\,MW}{750}-\underset{50\%\,MW}{375}) + 0.20(\underset{75\%\,MW}{562}-\underset{50\%\,MW}{375})\right]$$

$$= 3.9 \times 10^6\ \text{kwh/YR}$$

THEREFORE THE CAPITALIZED COST WILL BE AS FOLLOWS,

$$\text{UNIT 1 CAPITALIZED COST} = \frac{(3.9\times10^6\ \text{kwh/yr})\left(\frac{.55768}{8.1755}\ \$/\text{kwh}\right)}{0.1319} = 2.0\times10^6\ (\$1986)$$

$$\text{UNIT 2} = 2.0\times10^6\ (\$1986)$$

INCREASED EROSION DUE TO FLUE GAS RECIRCULATION WILL CAUSE APPROXIMATELY 10 HOURS OF UNIT DOWNTIME PER YEAR. THEREFORE, THE CAPITALIZED COST WILL BE AS FOLLOWS.

average load while operating

$$\text{UNIT 1 CAPITALIZED COST} = \frac{(10\ \text{HR})(750\ \text{MW})(1000\ \text{kw/mw})\left(\frac{0.55768}{8.1755}\right)(0.879)}{0.1319} = 3.4\times10^6\ (\$1986)$$

$$\text{UNIT 2} = 3.4\times10^6\ (\$1986)$$

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SUMMING THE SPECIFIC CAPITALIZED REPLACEMENT POWER COSTS YIELDS THE FOLLOWING TOTALS.

	UNIT 1 (10^6 \$1986)	UNIT 2 (10^6 \$1986)
FGR FAN FAILURE	2.0	2.0
CONVECTIVE PASS DESIGN	3.4	3.4
TOTAL	5.4	5.4

REPLACEMENT POWER COSTS DUE TO DELAY

THE 1986 COST OF REPLACEMENT POWER IS \$750,000 PER DAY. TO INSTALL A FLUE GAS RECIRCULATION SYSTEM IT WILL BE NECESSARY TO DELAY UNITS 1 & 2 BY TWO YEARS EACH. THEREFORE THE 1986 COST OF DELAYS TO INSTALL FGR WILL BE AS FOLLOWS.

$$\text{UNIT 1} = \text{UNIT 2} = (750{,}000\ \$/\text{day})(2\ \text{YEARS})(365\ \text{days}/\text{YEAR})$$

$$= 547.5 \times 10^6\ (1986\ \$)$$

THEREFORE THE TOTAL PROJECT COSTS WITH AN FGR SYSTEM WOULD BE AS FOLLOWS.

	UNIT 1 (10^6 \$1986)	UNIT 2 (10^6 \$1986)	UNIT 1 & 2 (10^6 \$1986)
PRESENT WORTH OF TOTAL CAPITAL COSTS	3349.4	695.1	4044.5
CAPITALIZED VALUE OF DIFF. ANNUAL OP. COSTS	9.4	9.1	18.5
CAPITALIZED REPLACEMENT POWER COSTS	5.4	5.4	10.8
REPLACEMENT POWER COSTS DUE TO DELAY	547.5	547.5	1095.0
TOTAL PROJECT COST W/ FGR	3911.7	1257.1	5168.8